BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In The Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY (U902E) for a Certificate of Public Convenience and Necessity for the South Orange County Reliability Enhancement Project	A. 12-05-020 (Filed May 18, 2012)

NOTICE OF ORAL AND WRITTEN EX PARTE COMMUNICATION

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Attorneys for The City of San Juan Capistrano

Dated: April 21, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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NOTICE OF ORAL AND WRITTEN EX PARTE COMMUNICATION

Pursuant to Rule 8.3 of the Commission's Rules of Practice and Procedure, the City of San Juan Capistrano (the City) submits this Notice of Oral and Written Ex Parte Communication.

On April 19, 2016, Dr. Dariush Shirmohammadi of Shir Consultants, consultant to the City, and Jeanne Armstrong of Goodin MacBride Squeri &Day, outside counsel to the City, met with Christine Hammond, Chief of Staff to Commissioner Michael Picker, at the Commission's San Francisco offices. The meeting, which was initiated by the City, lasted approximately 45 minutes.

Ms. Armstrong spoke about how San Diego Gas & Electric Company's proposed project alternative was addressing a bulk transmission need which does not exist and how the alternative supported by the City - upgrading the Rancho Mission Viejo Substation (Alternative F) - will address the reliability objectives of the project. Dr. Shirmohammadi addressed each of the alleged reliability concerns regarding Alternative F that have been raised in testimony by the California Independent System Operator, illustrating how each of those concerns could be addressed within WECC - NERC Reliability Standards. For purposes of his explanation, Dr. Shirmohammadi utilized some schematics which are appended to this notice. In addition, on April 20, 2016, Ms. Armstrong transmitted to Ms. Hammond via e-mail a copy of the WECC-

NERC Reliability Standards. A copy of the standards and the e-mail transmittal are appended to this notice.

For a copy of this notice please contact Wendy Peña at 415-392-7900 or wpena@goodinmacbride.com.

Respectfully submitted this April 21, 2016 at San Francisco, California.

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By *<u>/s/Jeanne B. Armstrong</u>*
Jeanne B. Armstrong

Attorneys for the City of San Juan Capistrano

3638/001/X181322.v1

ATTACHMENT 1

Figure 1. Southern Orange Country 230/138 kV System Configuration in the Year of 2011 (the existing system in the CAISO 2010-2011 TPP)

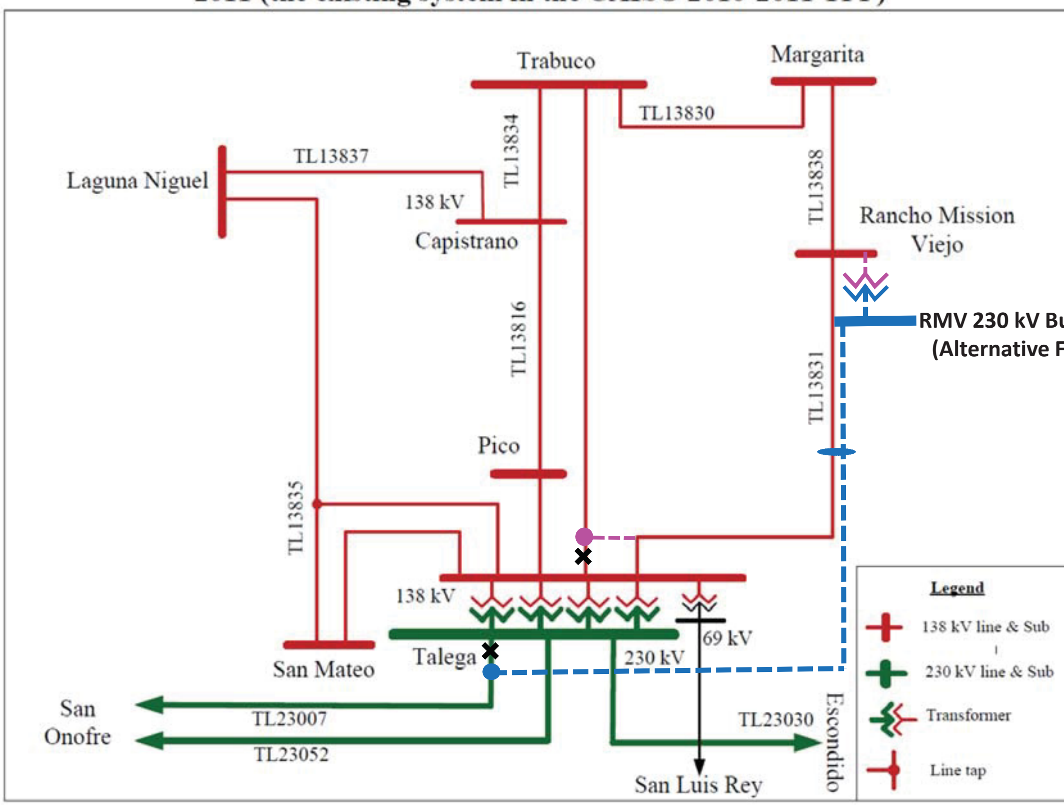
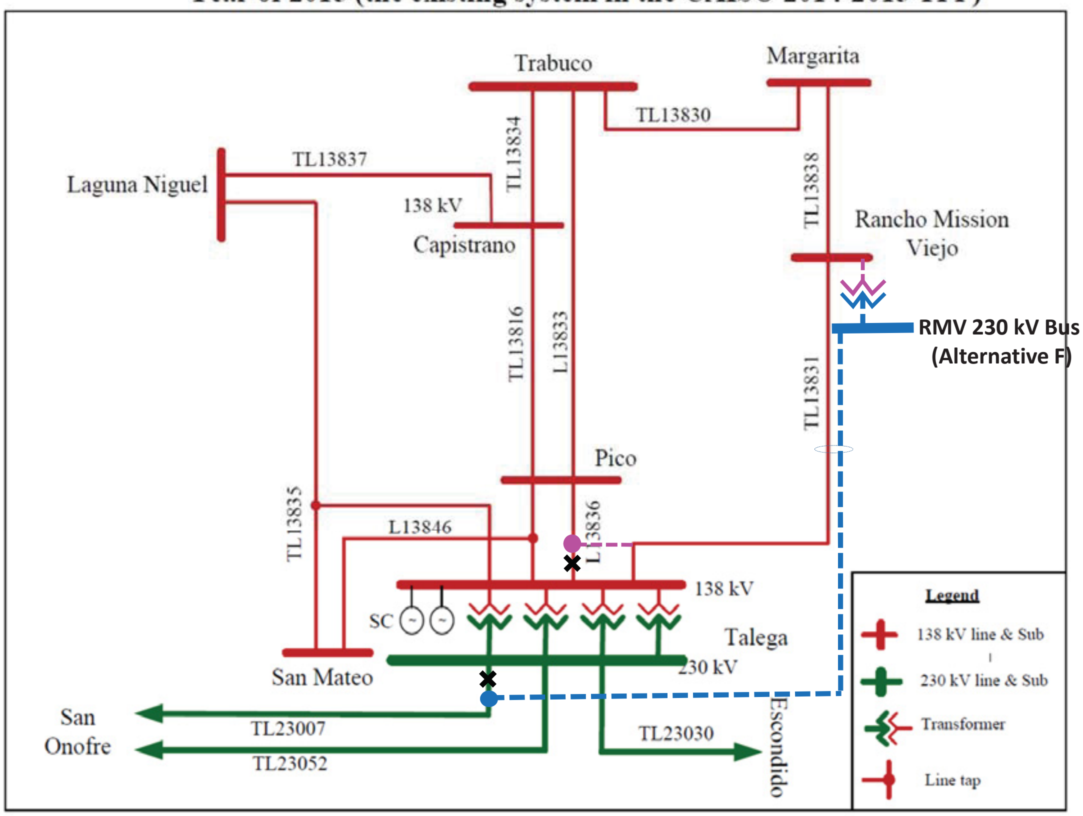


Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



CAISO Reliability Concerns with SJC Alternative F

ID	Overloaded Facility	Contingency	Category	Category Description	Thermal Loading (% over applicable rating)
					2024SP
24SP-F-c1	22840 TALEGA 138 22842 TA TAP33 138 1	TAP_2000_Line TALEGA-R.MSNVJO-PICO 138 kV Tap Circuit 1 -- RMV-L_011_Line S.ONOFRE 230.0 to RMVIEJO 230.0 Circuit 1	C	L-1-1	113.48
24SP-F-c2	22842 TA TAP33 138 22656 PICO 138 1	TAP_2000_Line TALEGA-R.MSNVJO-PICO 138 kV Tap Circuit 1 -- RMV-L_011_Line S.ONOFRE 230.0 to RMVIEJO 230.0 Circuit 1	C	L-1-1	109.67
24SP-F-c3	22841 TA TAP 138 22396 LAGNA NL 138 1	line_7002_Line CAPSTRNO 138.0 to PICO 138.0 Circuit 1 -- line_7007_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit 1	C	L-1-1	108.01
24SP-F-c4	22841 TA TAP 138 22396 LAGNA NL 138 1	)02_Line CAPSTRNO 138.0 to PICO 138.0 Circuit 1 -- line_7004_Line CAPSTRNO 138.0 to TRABUCO 138.0 Circuit 1	C	L-1-1	101.84
24SP-F-c5	22840 TALEGA 138 22842 TA TAP33 138 1	)07_Line R.MSNVJO 138.0 to MARGARTA 138.0 Circuit 1 -- TAP_2000_Line TALEGA-R.MSNVJO-PICO 138 kV Tap Circuit 1	C	L-1-1	100.35
24SP-F-c6	SDG&E's South Orange County Service Area	f Talega 138 kV Substation	D	Loss of substation (D8)	Load drop for the area

CAISO Contingencies 1 &2: Category C loss of two lines sharing a single tower

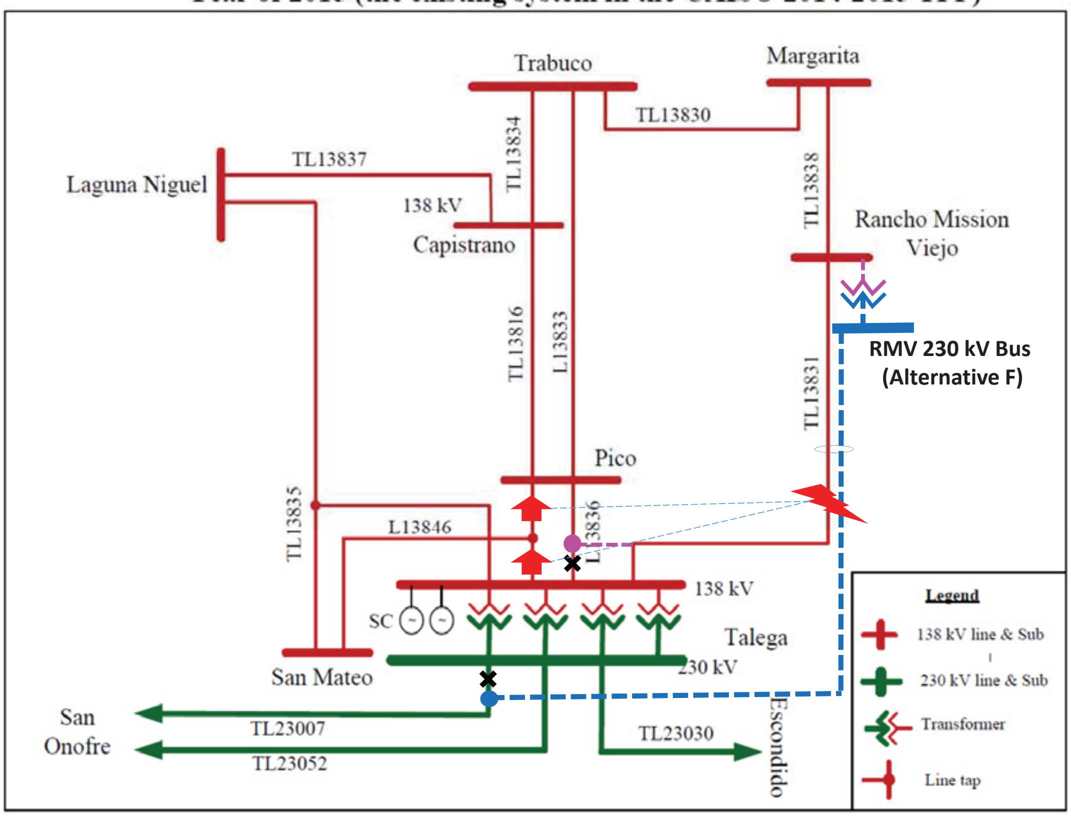
Chance of occurrence: ~0.000003%

Consequence: ~10% overload on a single line (~1 mile) between Talega and Pico subs

Solution: Controlled load drop (allowed per NERC/WECC reliability standards) – no possibility of cascading to bulk system

This overload may be simply avoided if the original SOC transmission loop without the latest tap configuration was used.

Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



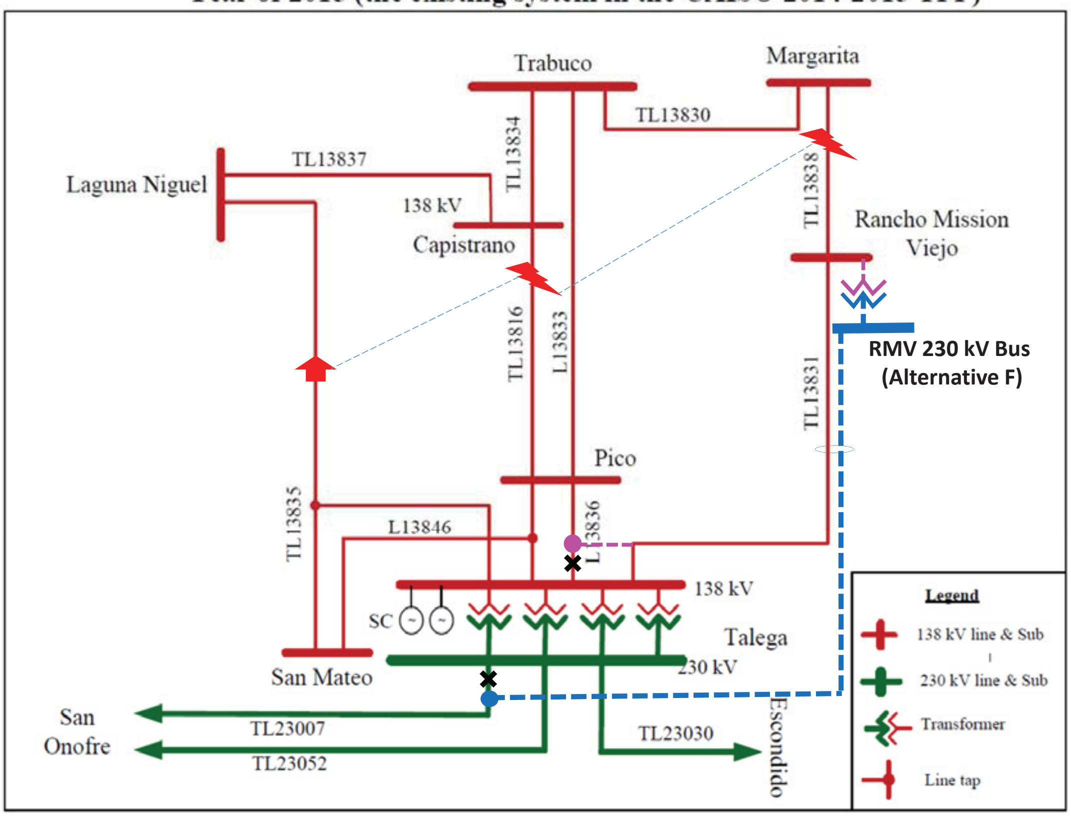
CAISO Contingency 3: Category C loss of two geographically separate lines

Chance of occurrence: ~0.00000000006%

Consequence: ~8% overload on part of a single line (~8 miles) between the tap point and Laguna Niguel Sub

Solution: Controlled load drop (allowed per NERC/WECC reliability standards) – no possibility of cascading to bulk system

Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



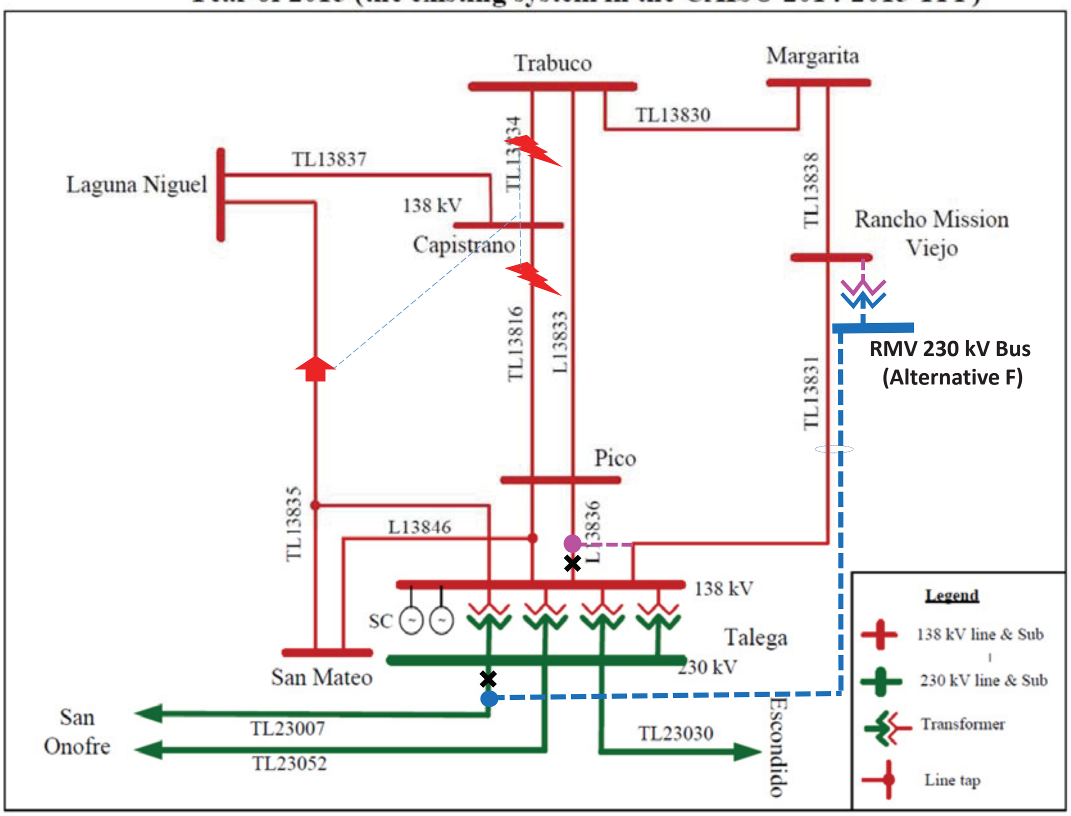
CAISO Contingency 4: Category C loss of two geographically separate lines (effectively the same as Contingency 3)

Chance of occurrence: ~0.00000000008%

Consequence: ~1% overload on part of a single line (~8 miles) between the tap point and Laguna Niguel Sub

Solution: Controlled load drop (allowed per NERC/WECC reliability standards) – no possibility of cascading to bulk system

Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



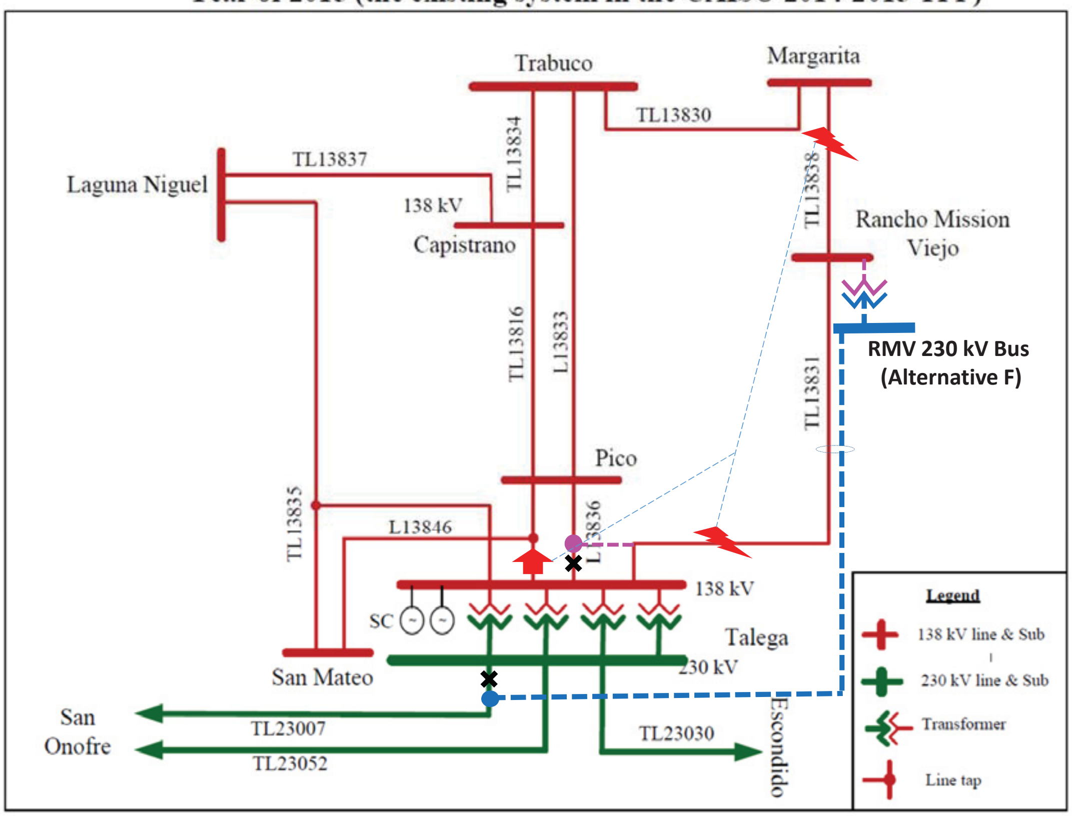
CAISO Contingency 5: Category C loss of two geographically separate lines

Chance of occurrence: ~0.00000000004%

Consequence: ~.4 % overload on fraction of a single line (a few hundred feet) between Talega and tap point

Solution: No solution necessary given the size of overload and length of the line

Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



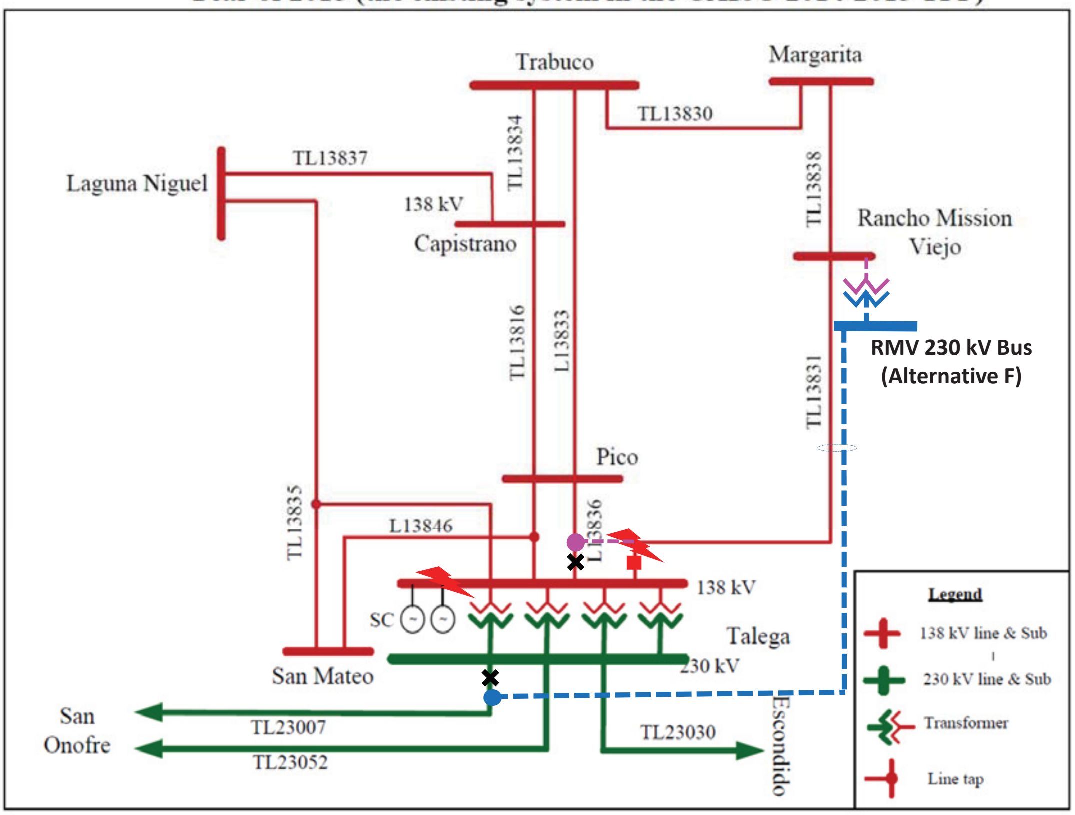
CAISO Contingency 6: Category "X" (Category D outage the entire Talega 138 kV switchyard plus a stuck breaker – itself a Category B outage)

Chance of occurrence: 0.00%

Consequence: Partial loss of SOC load

Solution: No solution necessary for such totally non-credible contingency

Figure 2. Southern Orange Country 230/138 kV System Configuration in the Year of 2015 (the existing system in the CAISO 2014-2015 TPP)



ATTACHMENT 2

WPena

From: JArmstrong
Sent: Wednesday, April 20, 2016 3:17 PM
To: 'Hammond, Christine J.'
Subject: WECC- NERC Reliability Standards
Attachments: WECC-NERC Reliability Standards.pdf

Christine

Thank you for meeting with Dariush and me yesterday. I have attached hereto the WECC-NERC Reliability standards which we were discussing. If you note, pages XI- 28 and XI-29 have been highlighted. These pages focus on the types of situations (contingencies) which allow for dropping load.

I will include this in my ex parte notice.

Jeanne

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GOODIN,
MACBRIDE,
SQUERI & DAY, LLP

SECTION XI

PLANNING AND OPERATING CRITERIA

REVISED

SEPTEMBER 2007

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Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

Revised April 10, 2003

Contents

Preface

*This document merges the WECC Planning Standards into the **NERC Planning Standards**. The WECC Planning Standards are indicated in italic and are preceded by headings WECC-S, WECC-M, or WECC-G, depending upon whether the differences are Standards, Measures or Guides. Certain aspects of the WECC standards are either more stringent or more specific than the NERC standards.*

The NERC standards and associated Table I are applicable to all systems, without distinction between internal and external systems. Unless otherwise stated, WECC standards and the associated WECC Disturbance-Performance Table of Allowable Effects on Other Systems are not applicable to internal systems.

It is intended that the WECC standards be periodically reviewed by the Reliability Subcommittee as experience indicates, in accordance with WECC's Process for Developing and Approving WECC Standards.

Foreword

This **NERC Planning Standards** report is the result of the NERC Engineering Committee's efforts to address how NERC will carry out its reliability mission by establishing, measuring performance relative to, and ensuring compliance with **NERC Policies**, **Standards**, **Principles**, and **Guides**. From the planning or assessment perspective, this report establishes **Standards** and defines in terms of **Measurements** the required actions or system performance necessary to comply with the **Standards**. This report also provides **Guides** that describe good planning practices for consideration by all electric industry participants.

Mandatory compliance with the **NERC Planning Standards** is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. This report, however, does not address issues of implementation, compliance, and enforcement of the **Standards**. The timing and manner in which implementation and enforcement of and compliance with the **NERC Planning Standards** will be achieved has yet to be defined.

Background

At its September 1996 meeting, the NERC Board of Trustees unanimously accepted the report, *Future Course of NERC*, of its Future Role of NERC Task Force - II. This report outlines several findings and recommendations on NERC's future role and responsibilities in the light of the rapidly changing electric industry environment.

The report also concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In accepting the Task Force's report, the Board also directed the NERC Engineering Committee and Operating Committee to develop appropriate implementation plans to address the recommendations in the *Future Course of NERC* report and to present these plans to the Board at its January 1997 meeting. The primary focus of the action plans and the initiatives from the Engineering Committee perspective was the development of **Planning Standards and Guides**. At its January 1997 meeting, the NERC Board of Trustees accepted the Engineering Committee's November 1996 "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides" report. This action plan formed the basis for the development of **NERC's Planning Standards**.

Standards Development

The Engineering Committee assigned the overall responsibility for the development and coordination of the **NERC Planning Standards** to its Reliability Criteria Subcommittee (RCS). The Engineering Committee's other subgroups were also called upon to provide major inputs to RCS in its **Planning Standards** development effort. These other subgroups included: the Reliability Assessment Subcommittee, the Interconnections Dynamics Working Group, the Multiregional Modeling Working Group, the System Dynamics Database Working Group, the Load Forecasting Working Group, and the Available Transfer Capability Implementation Working Group.

In the development of the **NERC Planning Standards**, all proposed **Standards, Measurements, and Guides** were distributed for Regional and electric industry review prior to their submittal to the Engineering Committee and Board for approval. The Engineering Committee recognized that the **NERC Planning Standards** would have to be more specific than in the past, and that differences among the Regions would still need to be considered. It also recognizes that the development of **Planning Standards** will be an evolutionary process with continual additions, changes, and deletions.

The Engineering Committee extends its appreciation to the members of its subgroups and the members of the Regions and electric industry sectors that commented on the proposed drafts of the **NERC Planning Standards** in their development phases. A substantial effort was expended to develop the **NERC Planning Standards** in a very short time frame.

Foreword

The **NERC Planning Standards** continue to define the reliability of the interconnected bulk electric systems using the following two terms:

- **Adequacy** - The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Security** - The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The Engineering Committee recognizes that this **NERC Planning Standards** report is the first such industry effort to establish industry **Planning Standards** requiring mandatory compliance by the Regions, their members, and all other electric industry participants. This report also defines the specific actions or system performance that must be met to ensure compliance with the **Planning Standards**.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and their capability to support a wide variety of transfers.

The future challenge to the reliability of the electric systems will be to plan and operate transmission systems so as to provide requested electric power transfers while maintaining overall system reliability.

Introduction

Electric system reliability begins with planning. The **NERC Planning Standards** state the fundamental requirements for planning reliable interconnected bulk electric systems. The **Measurements** define the required actions or system performance necessary to comply with the **Standards**. The **Guides** describe good planning practices and considerations.

With open access to the transmission systems in connection with the new competitive electricity market, all electric industry participants must accept the responsibility to observe and comply with the **NERC Planning Standards** and to contribute to their development and continued improvement. That is, compliance with the **NERC Planning Standards** by the Regional Councils (Regions) and their members as well as all other electric industry participants is mandatory.

The Regions and their members along with all other electric industry participants are encouraged to consider and follow the **Guides**, which are based on the **NERC Planning Standards**. The application of **Guides** is expected to vary to match load conditions and individual system requirements and characteristics.

Background

In January 1996, the NERC Board of Trustees formed a task force to reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. The task force's report, *Future Course of NERC*, accepted by the Board at its September 1996 meeting, concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In January 1997, the Board voted unanimously to obligate its Regional and Affiliate Councils and their members to promote, support, and comply with all NERC Planning and Operating Policies.

Regional Planning Criteria and Guides

The Regions, subregions, power pools, and their members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the **Planning Standards** and which reflect the diversity of individual electric system characteristics, geography, and demographics for their areas.

Therefore, all electric industry participants must also adhere to applicable Regional, subregional, power pool, and individual member planning criteria and guides. In those cases where Regional, subregional, power pool, and individual member planning criteria and guides are more restrictive than the **NERC Planning Standards**, the more restrictive reliability criteria and guides must be observed.

Responsibilities for Planning Standards, Measurements, and Guides

The NERC Board of Trustees approves the **NERC Planning Standards, Measurements, and Guides** to ensure that the interconnected bulk electric systems are planned reliably.

To assist the Board, the NERC Engineering Committee:

- Develops the **NERC Planning Standards, Measurements, and Guides** for the Board's approval, and
- Coordinates the **NERC Planning Standards, Measurements, and Guides**, as appropriate, with corresponding Operating Policies, Standards, Measurements, and Guides developed by the NERC Operating Committee.

The Regions, subregions, power pools, and their members:

- Develop planning criteria and guides that are applicable to their respective areas and which are in compliance with the **NERC Planning Standards,**
- Coordinate their planning criteria and guides with neighboring Regions and areas, and
- Agree on planning criteria and guides to be used by intra- and interregional groups in their planning and assessment activities.

Format of the NERC Planning Standards

The presentation of the **Planning Standards** in this report is based on the following general format:

- **Introduction** - Background and reason(s) for the **Standard(s)**.
- **Standard** - Statement of the specifics requiring compliance.
- **Measurement** - Measure(s) of performance relative to the **Standard**.
- **Guides** - Good planning practices and considerations that may vary for local conditions.
- **Compliance and Enforcement** - Not addressed in this report.

The **NERC Planning Standards** are in bold face type to distinguish them from the other sections of the report. In some cases, the **Measurements** of a Standard are multifaceted and address several characteristics of the bulk electric systems or system components.

Definition of Bulk Electric System

The **NERC Planning Standards, Measurements, and Guides** in this report are intended to apply primarily to the bulk electric systems, also referred to as the interconnected transmission systems or networks. Because of the individual character of each of the Regions, it is recommended that each Region define those facilities that are to be included as its bulk electric systems or interconnected transmission systems for which application of the **Planning Standards** will be required. Any differences from the following Board definition of bulk electric system shall be documented and reported to the NERC Engineering Committee prior to the application or implementation of the **Planning Standards** in this report.

The NERC Board of Trustees at its April 1995 meeting approved a definition for the bulk electric system as follows:

> **"The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher."**

This definition is included in the May 1995 NERC brochure on "Planning of the Bulk Electric Systems" prepared by a task force of the Engineering Committee.

A system facility, element, or component has been defined as any generating unit, transmission line, transformer, or piece of electrical equipment comprising an electric system. This definition is included in the May 1995 NERC *Transmission Transfer Capability* reference document.

Compliance With NERC Planning Standards

The interconnected bulk electric systems in the United States, Canada, and the northern portion of Baja California, Mexico are comprised of many individual systems, each with its own electrical characteristics, set of customers, and geographic, weather, and economic conditions, and regulatory and political climates. By their very nature, the bulk electric systems involve multiple parties. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the reliability of the other systems. Therefore, to maintain the reliability of the bulk electric systems or interconnected transmission systems or networks, the Regions and their members and all electric industry participants must comply with the **NERC Planning Standards**.

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand** - Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.

- **Provide Flexibility for Changing System Conditions** - Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

- **Reduce Installed Generating Capacity** - Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.

- **Allow Economic Exchange of Electric Power Among Systems** - Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Adequacy and Security (I.) are provided in the following sections:

A. Transmission Systems
B. Reliability Assessment
C. Facility Connection Requirements
D. Voltage Support and Reactive Power
E. Transfer Capability
F. Disturbance Monitoring

Introduction

The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and planned equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and projected electricity transfer levels.

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these I.A. Standards on Transmission Systems.

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

Standards

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category B of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions of the contingencies as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category C of Table I (attached).

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

WECC-S1 ***In addition to NERC Table I, WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems contained in this section when planning the Western Interconnection. The WECC Disturbance-Performance Table does not apply internal to a WECC Member System.***

WECC-S2 ***The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the common mode contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.***

WECC-S3 ***The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.***

WECC-S4 ***The loss of multiple bus sections as a result of a failure or delayed clearing of a bus tie or bus sectionalizing breaker shall meet the performance specified for Category D of the WECC Disturbance-Performance Table.***

WECC-S5 ***For contingencies involving existing or planned facilities, the Table W-1 performance category can be adjusted based on actual or expected performance (e.g. event outage frequency and consideration of impact) after going through the WECC Phase I Probabilistic Based Reliability Criteria (PBRC) Performance Category Evaluation (PCE) Process.***

WECC-S6 ***Any contingency adjusted to Category D must not result in a cascading outage unless the MTBF is greater than 300 years (frequency less than 0.0033 outages/year) or the initiating disturbances and corresponding impacts are confined to either a radial system or a local network.***

WECC-S7 ***For any event that has actually resulted in cascading, action must be taken so that future occurrences of the event will not result in cascading, or it must go through the PBRC process and demonstrate that the MTBF is greater than 300 years (frequency less than 0.0033 outages/year).***

WECC-S8 ***The WECC Planning Standards require systems to meet the same performance category for unsuccessful reclosing as that required for the initiating disturbance without reclosing.***

WECC-S9 ***To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards in Table W-1 for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these standards are more stringent, these standards may not be imposed on other systems. This does not relieve the system or group of systems from WECC standards for impacts on other systems.***

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

Notes:

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

3. *Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.*

Table W-1

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

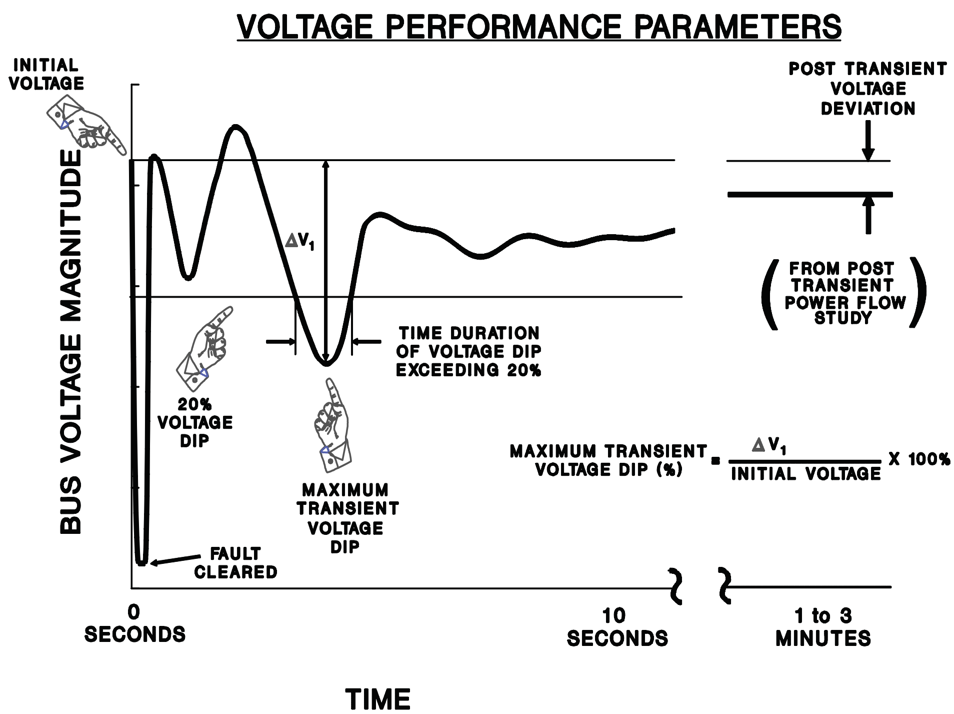

Figure W-1

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. All customer demands shall be supplied, and all projected firm (non-recallable reserved) transfers shall be maintained.
d. Stability of the network shall be maintained.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S1.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Be supported by a current or past study that addresses the plan year being assessed.
2. Address any planned upgrades needed to meet the performance requirements of Category A.
3. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that with all planned facilities in service (no contingencies), established normal (pre-contingency) operating procedures in place, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands.

Assessments shall include the effects of existing and planned reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category A of Table I.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. No loss of customer demand (except as noted in Table I, footnote b) shall occur, and no projected firm (non-recallable reserved) transfers shall be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S2. Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

2. Assessments shall address any planned upgrades needed to meet the performance requirements of Category B.
3. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that for system conditions where the initiating event results in the loss of a single generator, transmission circuit, or bulk system transformer, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. No planned loss of customer demand nor curtailment of projected firm transfers shall be necessary to meet these performance requirements, except as noted in footnote b of Table I. This system performance shall be achieved for the described contingencies of Category B of Table I.

Assessments shall consider all contingencies applicable to Category B, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category B of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category B of Table I.

The systems must be capable of meeting Category B requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M2), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 are as defined in Category C (event(s) resulting in the loss of two or more elements) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. Planned (controlled) interruption of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S3.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

2. Assessments of the near-term planning horizon shall be supported by a current or past study that addresses the plan year being assessed. For assessments of the longer-term planning horizon, a current or past study that addresses the plan year being assessed shall only be required if marginal conditions that may have longer lead-time solutions have been identified in the near-term assessment.

3. Assessments shall address any planned upgrades needed to meet the performance requirements of Category C.

System performance assessments based on system simulation testing shall show that for system conditions where (See Table I Category C)

1. The initiating event results in the loss of two or more elements, or
2. Two separate events occur resulting in two or more elements out of service with time for manual system adjustments between events,

and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. Planned outages of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed. This system performance shall be achieved for the described contingencies of Category C of Table I.

Assessments shall consider all contingencies applicable to Category C, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category C of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category C of Table I.

The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M3), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S4.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) planning horizons.

2. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

System performance assessments based on system simulation testing shall evaluate system conditions of Table I Category D, with all projected firm transfers modeled.

Assessments shall consider all contingencies applicable to Category D, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources, and shall include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems.

Assessments shall consider the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed when evaluating the effects of Category D events.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near-term (years one through five) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses.

Corrective Plan Requirements
None required.

Reporting Requirements
The documentation of results of these reliability assessments and mitigation measures shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M5. Entities responsible for the reliability of the interconnected transmission systems shall document their assessment activities in compliance with the I.B. Standard on Reliability Assessment to ensure that their respective systems are in compliance with these I.A. Standards on Transmission Systems. This documentation shall be provided to NERC on request. (S1, S2, S3, and S4)

Guides

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account the maintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7 Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm (non-recallable reserved) transmission services.

G8. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

G9. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G10. It may be appropriate to conduct the extreme contingency assessments on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

WECC-G1 ***The contingencies specified for each Category in the NERC table and the outage frequency range provided in the WECC table provide a basis for estimating performance categories for disturbances that are not in the NERC Table or for disturbances that have sufficient data available to estimate their probability of occurrence.***

WECC-G2 ***Each system should provide sufficient transmission capacity within its system to serve its load and meet its transmission obligations to others without unduly relying on or without imposing an undue degradation of reliability on any other system, unless pursuant to prior agreement with the system(s) so affected. Each system should provide sufficient transmission capacity, by ownership or agreement, for scheduling power transfers between its system and any other system. In transferring such power there should be no undue degradation of reliability on any system not a party to the transfer.***

WECC-G3 ***Each system should plan its system with adequate transfer capability so that its power transfers will not have an undue loop flow impact on other systems, and so that planned schedules do not depend on opposing loop flow to keep actual flows within the path transfer capability. A system adding facilities should recognize that the addition itself could result in a component of loop flow that should be accommodated. Loop flow is an inherent characteristic of interconnected AC transmission systems and the mere presence of loop flow on circuits other than those of the transfer path is not necessarily an indication of a problem in planning or in scheduling practices.***

WECC-G4 ***An initiating event of a three phase fault may be used for screening contingencies of two adjacent circuits. However, the required performance will be as specified in Table I for category C5 (Non three phase fault with Normal Clearing: Double Circuit Tower-line) events. Simulations meeting the criteria with a three-phase fault may be assumed to meet the criteria with a non-three phase fault and normal clearing.***

WECC-G5 ***Considerations in determining the probability of occurrence of an outage of two adjacent circuits on separate towers should include line design; length; location, environmental factors; outage history; operational guidelines; and separation between circuits.***

TERMS USED IN THE WECC PLANNING STANDARDS

Post Transient Voltage Deviation

In the context of these Planning Standards, post transient voltage deviation refers to "voltage drop" not "voltage rise," and the post-transient time frame is considered to be one to three minutes after a system disturbance occurs. This allows available automatic voltage support measures to take place, but does not allow the effects of operator manual actions or Area Generation Control response. The recommended simulation is a post transient power flow that simulates all automatic action but not manual actions and not area interchange control. The post transient voltage deviation standards do not fully identify all potential voltage collapse problems. Voltage collapse standards are discussed in greater depth in Standard I D.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple Circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

D[e] – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria

Introduction

NERC, through its Planning Committee (or successor group(s)), reviews and assesses the overall reliability (adequacy and security) of the interconnected bulk electric systems, both existing and as planned, to ensure that each Region (subregion) complies with the NERC Planning Standards and its own Regional planning criteria.

NERC also conducts special reliability assessments on a Regional, interregional, and Interconnection basis as conditions warrant or as requested by the NERC Planning Committee or Board of Trustees. Such special reliability assessments may include, among others, security assessments, operational assessments, evaluations of emergency response preparedness, adequacy of fuel supply and hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North America.

To carry out these reviews and assessments of the overall reliability of the interconnected bulk electric systems, NERC (and its Planning Committee or successor group(s)) must have sufficient data and input from the Regions to prepare and publish NERC's annual seasonal (summer and winter) and longer-range assessments of the reliability of the interconnected bulk electric systems. Additional data may also be required for the special reliability assessments.

NERC's adequacy and security assessments must ensure the requirements stated in each Region's planning criteria and the **NERC Planning Standards** are met.

The Regions must also assess their Regional bulk electric system reliability within the context of the interconnected networks. Therefore, the Region and its members must coordinate their assessment efforts not only within their Region, but also with neighboring systems and Regions.

Standards

S1. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region's respective Regional planning criteria.

Measurements

M1. Each Region shall annually conduct reliability assessments of its respective existing and planned Regional bulk electric system (generation and transmission facilities) for: 1) seasonal (winter and summer of the current year) conditions or other current-year system conditions as deemed appropriate by the Region, and 2) near-term (years one through five) and longer-term (years six through ten) planning horizons. For the near term, detailed assessments shall be conducted. For the longer term, assessment shall focus on the analysis of trends in resources and transmission adequacy, other industry trends and developments, and reliability concerns.

Similarly, the Regions shall also annually conduct interregional reliability assessments to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis to preserve the adequacy and security of the interconnected bulk electric systems.

Regional and interregional reliability assessments shall demonstrate that the performance of these systems are in compliance with NERC Standard I.A and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.

Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.

In addition, special reliability assessments shall also be performed as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, among others, security assessments, operational assessments, evaluations of emergency response preparedness, adequacy of fuel supply and hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North America.

M2. Each Region shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and bulk electric system data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Planning Standards and the respective Regional planning criteria.

The facility and bulk electric system data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

1. Electric Demand and Net Energy for Load (actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of demand-side management)

2. Resource Adequacy and Supporting Information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements)

3. Demand-Side Resources and Their Characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations)

4. Supply-Side Resources and Their Characteristics (existing and planned generator units, ratings, performance characteristics, fuel types and availability, and real and reactive capabilities)

5. Transmission System and Supporting Information (thermal, voltage, and stability limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems)

6. System Operations and Supporting Information (extreme weather impacts, interchange transactions, and congestion impacts on the reliability of the interconnected bulk electric systems)

7. Environmental and Regulatory Issues and Impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation)

Introduction

All facilities involved in the generation, transmission, and use of electricity must be properly connected to the bulk interconnected transmission systems (generally 100 kV and higher) to avoid degrading the reliability of the electric systems to which they are connected.

To avoid adverse impacts on reliability when making connections to the interconnected bulk electric systems, generation and transmission owners and electricity end-users must meet facility connection and performance requirements as specified by those responsible for the reliability of the bulk interconnected transmission systems.

Standards

S1. Facility connection requirements shall be documented, maintained, and published by voltage class, capacity, and other characteristics that are applicable to generation, transmission, and electricity end-user facilities which are connected to, or being planned to be connected to, the bulk interconnected transmission systems.

S2. Generation, transmission, and electricity end-user facilities, and their modifications, shall be planned and integrated into the interconnected transmission systems in compliance with NERC Planning Standards, applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

Measurements

M1. Transmission providers, in conjunction with transmission owners, shall document, maintain, and publish facility connection requirements for

a. generation facilities,
b. transmission facilities, and
c. end-user facilities

to ensure compliance with **NERC Planning Standards** and applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria and facility connection requirements.

Facility connection requirements shall address, but are not limited to, the following items:

1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

3. Voltage level and MW and Mvar capacity or demand at point of connection.
4. Breaker duty and surge protection.
5. System protection and coordination.
6. Metering and telecommunications.
7. Grounding and safety issues.
8. Insulation and insulation coordination.
9. Voltage, reactive power, and power factor control.
10. Power quality impacts.
11. Equipment ratings.
12. Synchronizing of facilities.
13. Maintenance coordination.
14. Operational issues (abnormal frequency and voltages).
15. Inspection requirements for existing or new facilities.
16. Communications and procedures during normal and emergency operating conditions.

Facility connection requirements shall be maintained and updated as required.

Documentation of these requirements shall be available to the users of the transmission systems, the Regions, and NERC on request (five business days). (S1)

M2. Those entities responsible for the reliability of the interconnected transmission systems and those entities seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems and to ensure compliance with **NERC Planning Standards** and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

The entities involved shall present evidence that they have cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved. Assessments shall include steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under Standard I.A.

Documentation of these assessments shall include study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

This documentation shall be retained for three years and shall be provided to the Regions and NERC on request (within 30 days). (S2)

Guides

G1. Inspection requirements for connected facilities or new facilities to be connected should be included in the facility connection requirements documentation.

G2. Notification of new facilities to be connected, or modifications of existing facilities already connected to the interconnected transmission systems should be provided to those responsible for the reliability of the interconnected transmission systems as soon as feasible to ensure that a review of the reliability impact of the facilities and their connections can be performed and that the facilities are placed in service in a timely manner.

G3. Use of common data and modeling techniques is encouraged.

Introduction

Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (MWs), reactive power (Mvars) cannot be transmitted over long distances and must be supplied locally.

Standard

S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.

WECC-S1 ***For transfer paths, post-transient voltage stability is required with the path modeled at a minimum of 105% of the path rating (or Operational Transfer Capability) for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the path modeled at a minimum of 102.5% of the path rating (or Operational Transfer Capability).***

WECC-S2 ***For load areas, post-transient voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modeled at a minimum of 102.5% of the reference load level. For this standard, the reference load level is the maximum established planned load limit for the area under study.***

WECC-S3 ***Specific requirements that exceed the minimums specified in I.D WECC-S1 and S2 may be established, to be adhered to by others, provided that technical justification has been approved by the Planning Coordination Committee of the WECC.***

WECC-S4 ***These Standards apply to internal WECC Member Systems as well as between WECC Member Systems.***

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems. Documentation of these assessments shall be provided to the Regions and NERC on request. (S1)

M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:

a. Coordination of generator step-up transformer impedance and tap specifications and settings,
b. Calculation of underexcited limits based on machine thermal and stability considerations, and
c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges. (S1)

Guides

G1. Transmission owners should plan and design their reactive power facilities so as to ensure adequate reactive power reserves in the form of dynamic reserves at synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) in anticipation of system disturbances. For example, fixed and mechanically-switched shunt compensation should be used to the extent practical so as to ensure reactive power dynamic reserves at generators and SVCs to minimize the impact of system disturbances.

G2. Distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems.

G3. At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less.

If a synchronous generator does not meet this requirement, the generation owner should make alternate arrangements for supplying an equivalent dynamic reactive power capability to meet the area's reactive power requirements.

G4. Reactive power compensation should be close to the area of high reactive power consumption or production.

G5. A balance between fixed compensation, mechanically-switched compensation, and continuously-controlled equipment should be planned.

G6. Voltage support and voltage collapse studies should conform to Regional guidelines.

G7. Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

G8. Consideration should be given to generator shaft clutches or hydro water depression capability to allow generators to operate as synchronous condensers.

WECC-G1 ***Each system should plan and provide, by ownership or agreement, sufficient reactive power capacity and voltage control facilities to satisfy the requirements of its own system***

WECC-G2 ***Reactive Power Margin Requirements: The development of "Reactive Power Margin Requirements" based on the V-Q methodology developed by TSS (e.g., 400 MVAR at a particular bus) provides one alternate way to screen cases and determine whether or not they likely meet this criteria. The "Reactive Power Margin Requirement" is a proxy for Standards I.D WECC-S1 through WECC-S3.***

WECC-G3 ***Identification of Critical Conditions: It may be necessary to study a variety of load, transfer, and generation patterns to identify the most critical set of system conditions. For example, various conditions should be considered, such as: peak load conditions with maximum imports, low load conditions with minimum generation, and maximum interface flow conditions with worst case load conditions.***

WECC-G4 ***When developing the 105% and 102.5% load or transfer cases to demonstrate conformance with I.D WECC-S1, S2, and S3, conformance with the***

performance requirement (e.g., facility thermal loading limits) identified in Section I.A is not required.

WECC-G5 ***Load Voltage Response Assumption: Loads and distribution regulating devices in the study area should be modeled as detailed as is practical. If detailed load models cannot be estimated, the loads can be represented as constant MVA in long-term (post transient) voltage stability study; this representation approximates the effect of voltage regulation by LTC bulk power delivery transformers and distribution voltage regulators. For short-term (transient) voltage stability and dynamic simulation, dynamic modeling of induction motors is recommended.***

WECC-G6 ***Load Shedding: Controlled load interruption, as allowed in Table I of the NERC/WECC Planning Standards, is allowed to meet these standards.***

WECC-G7 ***Automatic Switching: Planned operation of automatic switching (distribution voltage regulators, switched static devices, etc.) may be modeled to meet these standards.***

WECC-G8 ***Voltage magnitudes alone are poor indicators of voltage stability or security because the system may be near collapse even if voltages are near normal depending on the system characteristics. The system should be planned so that there is sufficient margin between normal operating point and the collapse point to allow for reliable system operation.***

WECC-G9 ***In assessing the requirements under WECC-S3, relevant system variations and uncertainties should be considered. Types of analysis that may be used include P-V, V-Q, and dynamic studies.***

WECC-G10 ***Voltage stability analysis and the evaluation of balance between dynamic and static reactive power resources may be performed using the methodologies adopted by TSS.***

Introduction — Total and Available Transfer Capabilities

A competitive electricity market is dependent on the availability of transmission services. The availability of these services must be based on the physical and electrical characteristics and capabilities of the interconnected transmission networks as reliably planned and operated under the **NERC Planning Standards**, the NERC Operating Policies, and applicable Regional, subregional, power pool, and individual system criteria.

The total transfer capability (TTC) and the available transfer capability (ATC) for particular directions must be available to the market participants. These transfer capabilities are generally calculated through computer simulations of the interconnected transmission systems under a specific set of system conditions.

TTC and ATC values must balance both technical and commercial issues. The definitions of the key TTC and ATC transfer capability terms that bridge the technical characteristics of interconnected transmission system performance and the commercial requirements associated with transmission service requests are as follows:

- The total transfer capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

- Available transfer capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as TTC less existing transmission commitments (including retail customer service), less a capacity benefit margin (CBM)), less a transmission reliability margin (TRM). (The transfer capability margins - CBM and TRM - are defined under section I.E.2 of the Planning Standards document.)

  ATC is expressed as:

  ATC = TTC – Existing Transmission Commitments (includes retail customer service) – CBM – TRM

  Depending on the methodology used, either ATC or TTC may be calculated first.

TTC and ATC values are projected values. They are intended to indicate the available transfer capabilities of the interconnected transmission network.

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above

NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

a. Include a narrative explaining how TTC and ATC values are determined.
b. Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.
c. Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.
d. Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)
e. Require that TTC and ATC values and postings within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.
f. Indicate the treatment and level of customer demands, including interruptible demands.
g. Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

h. Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.
i. Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market. (S1

Each Region's procedure shall specify (S1):

a. The name, telephone number, and email address of a contact person to whom concerns are to be addressed.
b. The amount of time it will take for a response.
c. The manner in which the response will be communicated (e.g., email, letter, telephone, etc.).
d. What recourse a customer has if the response is deemed unsatisfactory.

Guides

G1. The Regional responses to transmission user concerns or questions regarding the ATC and TTC methodology and values of the transmission provider(s) should be made publicly available, possibly on a web site, for consistency and to avoid duplicative customer questions.

Introduction — Transfer Capability Margins

In defining the components that comprise Available Transfer Capability (ATC), two transmission transfer capability margin terms, known as Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), are introduced.

The definitions for CBM and TRM are:

- Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

- Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The methodologies used to determine CBM and TRM and the resulting CBM and TRM values impact ATC and, therefore, must be available to the market participants.

Standards

S1 Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region’s CBM methodology shall (S1):

a. Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b. Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c. Require that generation unit outages considered in a transmission provider’s CBM calculation be restricted to those units within the transmission provider’s system.
d. Require that CBM be preserved only on the transmission provider’s system where the load serving entity’s load is located (i.e., CBM is an import quantity only).
e. Describe the inclusion or exclusion rationale for generation resources of each LSE including those generation resources not directly connected to the transmission provider’s system but serving LSE loads connected to the transmission provider’s system.
f. Describe the inclusion or exclusion rationale for generation connected to the transmission provider’s system but not obligated to serve native/network load connected to the transmission provider’s system.

g. Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.
h. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.
i. Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).
j. Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

Each Regional CBM methodology shall address each of the items listed above and shall explain its use, if any, in determining CBM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining CBM values.

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a. Indicate the frequency under which the verification review shall be implemented.
b. Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
c. Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning

criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

d. Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.

The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of electrical energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall:

a. Require that CBM is to be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish operating reserves.
b. Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.
c. Describe the conditions under which CBM may be available as non-firm transmission service. (S1)

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of

CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a. Specify the update frequency of TRM calculations.
b. Specify how TRM values are incorporated into ATC calculations.
c. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values.

   The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

   Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

d. Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.
e. Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

Each Regional TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

The most recent version of the documentation of each Region's methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M7. Eliminated. Requirements included in Measurement M8.

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)

This Regional procedure shall:

a. Indicate the frequency under which the verification review shall be implemented.
b. Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.
c. Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.
d. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.

The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Introduction

Recorded information about transmission system faults or disturbances is essential to determine the performance of system components and to analyze the nature and cause of a disturbance. Such information can help to identify equipment misoperations, and the causes of oscillations that may have contributed to a disturbance. Protection system and control deficiencies can also be analyzed and corrected, reducing the risk of recurring misoperations. Transient modeling data can be gathered from fault and sequence-of-event monitoring equipment and long-time modeling data can be gathered from dynamic monitoring equipment using wide-area measurement techniques or swing sensors.

Standards

S1. Requirements shall be established on a Regional basis for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances.

S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.

Measurements

M1. Each Region shall develop comprehensive requirements for the installation of disturbance monitoring equipment to ensure data is available to determine system performance and the causes of system disturbances.

The comprehensive Regional requirements shall include the following items:

Technical requirements:

1. Type of data recording capability (e.g., sequence-of-event, fault recording, dynamic disturbance recording)
2. Equipment characteristics (e.g., recording duration requirements, time synchronization requirements, data format requirements, event triggering requirements)
3. Monitoring, recording, and reporting capabilities of the equipment (e.g., voltage, current, MW, Mvar, frequency)
4. Data retention capabilities (e.g., length of time data is to be available for retrieval)

Criteria for the location of monitoring equipment:

5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)
6. Installation requirements (e.g., substations, transmission lines, generators)

Testing and maintenance requirements:

7. Responsibility for maintenance and/or testing

Documentation requirements:

8. Requirements for periodic updating, review, and approval of the Regional requirements

The Regional requirements shall be provided to other Regions and NERC on request (five business days).

M2. Regional members shall provide to their respective Regions a list of their disturbance monitoring equipment that is installed and operational in compliance with Regional requirements. (S1)

M3. Each generation owner and transmission provider shall maintain a database of all disturbance monitoring equipment installations, and shall provide such information to the Region and NERC on request. (S1)

M4. Each Region shall establish requirements for providing disturbance monitoring data to ensure that data is available to determine system performance and the causes of system disturbances. Documentation of Regional data reporting requirements shall be provided to appropriate Regions and NERC on request. (S2)

M5. Regional members shall provide to their respective Regions system fault and disturbance data in compliance with Regional requirements. Each Region shall maintain and annually update a database of the recorded information. (S1, S2)

M6. Regional members shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models. (S2)

Guides

G1. Data from transmission system disturbance monitoring equipment should be in a consistent, time synchronized format.

G2. The Regional database should be used to identify locations on the transmission systems where additional disturbance monitoring equipment may be needed.

G3. The monitored data from disturbance monitoring equipment should be used to develop, maintain, validate, and enhance generator performance models and steady-state and dynamic system models.

G4. Each Region should establish and coordinate the requirements for the installation of disturbance monitoring equipment with neighboring Regions.

System modeling is the first step toward reliable interconnected transmission systems. The timely development of system modeling data to realistically simulate the electrical behavior of the components in the interconnected networks is the only means to accurately plan for reliability. To achieve this purpose, the **NERC Planning Standards** on System Modeling Data Requirements (II) establishes a set of common objectives for the development and submission of necessary data for electric system reliability assessment.

The detail in which the various system components are modeled should be adequate for all intra- and interregional reliability assessment activities. This means that system modeling data should include sufficient detail to ensure that system contingency, steady-state, and dynamic analyses can be simulated. Furthermore, any qualified user should be able to recognize significant limiting conditions in any portion of the interconnected transmission systems.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Modeling Data Requirements (II) are provided in the following sections:

A. System Data
B. Generation Equipment
C. Facility Ratings
D. Actual and Forecast Demands
E. Demand Characteristics (Dynamic)

These **Standards, Measurements, and Guides** shall apply to all system modeling necessary to achieve interconnected transmission system performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

Complete, accurate, and timely data is needed for system analyses to ensure the adequacy and security of the interconnected transmission systems, meet projected customer demands, and determine the need for system enhancements or reinforcements.

System analyses include steady-state and dynamic (all time frames) simulations of the electrical networks. Data requirements for such simulated modeling include information on system components, system configuration, customer demands, and electric power transactions.

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. All the users of the interconnected transmission systems shall provide appropriate equipment characteristics, system data, and existing and future interchange transactions in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A.S1, M2 for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A.S1, M2). If no schedule exists, then data shall be provided on request (30 business days).

M2. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.

The following list describes the steady-state data that shall be addressed in the Interconnection-wide requirements:

1. Bus (substation and switching station): name, nominal voltage, electrical demand (load) supplied (consistent with the aggregated and dispersed substation demand data supplied per Standard II.D.), and location.

2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.

3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), equipment status, and metering locations.

4. DC Transmission Line (overhead and underground): Line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.

5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), and equipment status.

6. Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.

7. Interchange Transactions: Existing and future interchange transactions and/or assumptions.

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected transmission systems on request (five business days).

M3. All users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A.S1, M4 for the modeling and simulation of the dynamics behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M4). If no schedule exists, then data shall be provided on request (30 business days).

M4. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western and

ERCOT. Within an interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. The following list describes the dynamics data that shall be addressed in the Interconnection-wide requirements:

1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

   However, estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

   The Interconnection-wide requirements shall specify unit size thresholds for permitting: 1.) the use of non-detailed vs. detailed models, 2.) the netting of small generating units with bus load, and 3.) the combining of multiple generating units at one plant.

2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static var controls (SVC), high voltage direct current systems (HVDC), flexible AC transmission systems (FACTS), and static compensators (STATCOM).

3. Dynamics data representing electrical demand (load) characteristics as a function of frequency and voltage.

4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Standard II.A.S1, M1.

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected systems on request (five business days).

M5. Data requirements for the steady-state and dynamics modeling of other associated transmission and generation facilities are included under the following sections of the **Standards**:

- Voltage Support and Reactive Power (I.D.)
- Disturbance Monitoring (I.F.)
- Generation Equipment (II.B.)

- Facility Ratings (II.C.)
- System Protection and Control (III)
- System Restoration (IV)

M6. Load-serving entities shall provide actual and forecast demands for their respective customers for steady-state and dynamics system modeling as specified in the respective steady-state and dynamics procedural manuals for the Interconnections and in compliance with the Actual and Forecast Demands (II.D.) and Demand Characteristics (Dynamic) (II.E.) Standards in this report. (S1)

Guides

G1. Any changes to interconnection tie line data should be agreed upon by all involved facility owners.

G2. The in-service date should be the year and season that a facility will be operable or placed in service.

G3. The out-of-service date should be the year and season that the facility will be retired or taken out of service.

G4. All data should be screened to detect inappropriate or inaccurate data.

G5. The reactive limits of generators should be periodically reviewed and field tested, as appropriate, to ensure that reported var limits are attainable. (See Generation Equipment Standard II.B.)

G6. Generating station service load (SSL) and auxiliary load representations should be provided to those entities responsible for the reliability of the interconnected transmission systems on request. The presence of SSL in a dynamic simulation will alter the bus angles derived from solution. This change in angle can be significant from the steady-state, dynamic, and voltage control perspectives, especially for large generating units.

G7. To accurately model system inertia, the netting of generation and customer demand should be avoided. For smaller units, the netting of generation and load is acceptable.

G8. Generating units equal to or greater than 50 MVA should generally be individually modeled. To maintain sufficient detail in the model, larger units should not be lumped together.

G9. Smaller generating units at a particular station may be lumped together and represented as one unit. The lumping of generating units at a station is acceptable where all units have the same electrical and control characteristics. Equivalent lumped units should generally not exceed 300 MVA.

G10. The dynamics data for each generating unit should be supplied on the machine's own MVA and kV base.

G11. Data for generator step-up transformers that are modeled as part of the generator data record should include effective tap ratios and per unit impedance (R and X values) on the transformer's MVA and kV base.

G12. Generator models should conform to *IEEE Guide for Synchronous Generator Modeling Practices in Stability Analysis* (IEEE Std. 1110-1991), or successor, Table 1, model 2.1 (for wound rotor machines) or 2.2 (for round rotor machines).

G13. Models of excitation systems, voltage regulators, and power system stabilizers should conform to *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies* (IEEE Std. 421.5-1992), or successor, if a model appropriate to the equipment is available. If no model having the required characteristics is available, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Computer Models for Representation of Digital-Based Excitation Systems", IEEE Working Group Report, *IEEE Transactions on Energy Conversion, Vol. 11., No. 3, September 1996*, should be considered in developing models of digital-based excitation systems.

G14. Models of turbine-governor systems for steam units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec 1973*, model 1. If this model lacks the characteristics required to represent the dynamic response of the turbine governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Dynamic Models for Fossil Fueled Steam Units in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.6, No. 2, May 1991*, should be considered in developing models of steam turbine governor systems.

G15. Models of turbine-governor systems for hydro units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec. 1973,* model 2. If this model lacks the characteristics required to represent the dynamic response of the turbine governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.7., No. 1,* *February 1992*, should be considered in developing models of hydro turbine governor systems.

G16. Models of turbine-governor systems for combustion turbine units should represent appropriate gains, limits, time constants and damping, and should include a parameter explicitly setting the ambient temperature load limit if this limits unit output for ambient temperatures expected during the season under study. "Dynamic Models for Combined Cycle Plants in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.9., No. 3, August 1994*, should be considered in developing models of combustion turbine governor systems.

Introduction

Validation of generator modeling data through field verification and testing is critical to the reliability of the interconnected transmission systems. Accurate, validated generator models and data are essential for planning and operating studies used to ensure electric system reliability.

Generating capability to meet projected system demands and provide the required amount of generation capacity margins is necessary to ensure service reliability. This generating capability must be accounted for in a uniform manner that ensures the use of realistically attainable values when planning and operating the systems or scheduling equipment maintenance.

Synchronous generators are the primary means of voltage and frequency control in the bulk interconnected electric systems. The correct operation of generator controls can be the crucial factor in whether the electric systems can sustain a severe disturbance without a cascading breakup of the interconnected network. Generator dynamics data is used to evaluate the stability of the electric systems, analyze actual system disturbances, identify potential stability problems, and analytically validate solutions for the identified problems.

Generator reactive capability is commonly derived from the generator real and reactive capability curves supplied by the manufacturer. Reactive power generation limits derived in this manner can be optimistic as heating or auxiliary bus voltage limits may be encountered before the generator reaches its maximum sustained reactive power capability. Manufacturer-provided design data may also not accurately reflect the characteristics of operational field equipment because settings can drift and components deteriorate over time. Field personnel may also change equipment settings (to resolve specific local problems) that may not be communicated to those responsible for developing a system modeling database and conducting system assessments. It is important to know the actual reactive power limits, control settings, and response times of generation equipment and to represent this information accurately in the system modeling data that is supplied to the Regions and those entities responsible for the reliability of the interconnected transmission systems.

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurements

M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures. (S1)

M2. Generation equipment owners shall annually test to verify the gross and net dependable capability of their units. They shall provide the Regions with the following information on request:

a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.

b. Active or real power requirements of auxiliary loads.

c. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M3. Generation equipment owners shall test to verify the gross and net reactive power capability of their units at least every five years. They shall provide the Regions with the following information on request:

a. Maximum sustained reactive power capability (both lagging and leading) as a function of real power output and generator terminal voltage. If safety or system conditions do not allow testing to full capability, computations and engineering reports of estimated capability shall be provided.

b. Reason for reactive power limitation.

c. Reactive power requirements of auxiliary loads.

d. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M4. Generation equipment owners shall test voltage regulator controls and limit functions at least every five years. Upon request, they shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting. (S1)

M5. Generation equipment owners shall test speed/load governor controls at least every five years. Upon request, they shall provide the Regions with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system. (S1)

M6. Generation equipment owners shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. Design data for new or refurbished excitation systems shall be provided at least one year prior to the in-service date with updated data provided once the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.) (S1)

Guides

G1. The following guidelines should be observed during testing of the reactive power capability of a generator:

a. The reactive power capability curve for each generating unit should be used to determine the expected reactive power capability.

b. Units should be tested while maintaining the scheduled voltage on the system bus. Coordination with other units may be necessary to maintain the scheduled voltage.

c. Hydrogen pressure in the generating unit should be at rated operating pressure.

d. Overexcited tests should be conducted for a minimum of two hours or until temperatures have stabilized.

e. When the maximum sustained reactive power output during the test is achieved, the following quantities should be recorded: generator gross MW and Mvar output, auxiliary load MW and Mvar, and generator and system voltage magnitudes.

G2. Most modern voltage regulators have limiting functions that act to bring the generating unit back within its capabilities when the unit experiences excessive field voltage, volts per hertz, or underexcited reactive current. These limiters are often intended to coordinate with other controls and protective relays. Testing should be done that demonstrates correct action of the controls and confirms the desired set points.

G3. Generation equipment owners should make a best effort to verify data necessary for system dynamics studies. An "open circuit step in voltage" is an easy to perform test that can be used to validate the generating unit and excitation system dynamics data. The open circuit test should be performed with the unit at rated speed and voltage but with its breakers open. Generator terminal voltage, field voltage, and field current (exciter field voltage and current for brushless excitation systems) should be recorded with sufficient resolution such that the change in voltages and current are clearly distinguishable.

G4. More detailed test procedures should be performed when there are significant differences between "open circuit step in voltage" tests and the step response predicted with the model data. Generator reactance and time constant data can be derived from standstill frequency response tests.

G5. The response of the speed/load governor controls should be evaluated for correct operation whenever there is a system frequency deviation that is greater than that established by the Regional procedures.

Introduction

Knowledge of facility ratings is essential for the reliable planning and operation of the interconnected transmission systems. Such ratings determine acceptable electrical loadings on equipment, before, during, and after system contingencies, and together with consideration of network voltage and system stability, determine the capability of the systems to deliver electric power from generation to point of use.

Standard

S1. Electrical facilities used in the transmission, and storage of electricity shall be rated in compliance with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

Measurements

M1. Facility owners shall document the methodology (or methodologies) used to determine their electrical facility ratings. Further, the methodology(ies) shall be compliant with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

The documentation shall include the methodology(ies) used to determine transmission facility ratings for both normal and emergency conditions. It shall also include methods for rating:

1. Transmission lines,
2. Transformers,
3. Series and shunt reactive elements,
4. Terminal equipment (e.g., switches, breakers, current transformers, etc.), and
5. Electrical energy storage devices (e.g., superconducting magnetic energy storage (SMES) system).

The rating of a transmission circuit shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.

Facility rating deviations from the methodology(ies), such as providing a consistent basis for jointly-owned facilities and unique applications, shall be documented. Ratings of jointly-owned facilities shall be coordinated and provided on a consistent basis.

The documentation shall identify the assumptions used to determine each of the facility ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.

The documentation of the methodology(ies) used to determine transmission facility ratings shall be provided to the Regions and NERC on request (five business days).

M2. Facility owners shall have on file, or be able to readily provide, a document or data base identifying the normal and emergency ratings of all of their transmission facilities (e.g., lines, transformers, reactive devices, terminal equipment, and storage devices) that are part of the bulk interconnected transmission systems. Seasonal variations in ratings shall be included as appropriate.

The ratings shall be consistent with the methodology(ies) for determining facility ratings (Standard II.C. S1, M1) and shall be updated as facility changes occur. The rating*s* shall be provided to the Regions and NERC on request (30 business days).

Guides

G1. System modeling should use facility ratings based on weather assumptions appropriate for the seasonal (demand) conditions being evaluated.

G2. Facility ratings should be based on or adhere to applicable national electrical codes and electric industry rating practices consistent with good engineering practice.

G3. The ratings of bypass equipment do not need to be included in the facility rating determination. However, if it is the most limiting element, it should be identified and made available to the system operator. If an equipment failure results in extended use of bypass equipment, then the facility rating should be adjusted in the model and the Region and impacted operating entities should be informed.

Introduction

Actual demand data is needed for forecasting future electrical requirements, reliability assessments of past electric system events, load diversity studies, and validation of databases.

Forecast demand data is needed for system modeling and the analysis of the adequacy and security of the interconnected bulk electric systems, and for identifying the need and timing of system reinforcements to reliably supply customer electrical requirements.

Actual and forecast demand data generally includes hourly, monthly, and annual demands and monthly and annual net energy for load. This data may be required on an aggregated Regional, subregional, power pool, individual system basis, or on a dispersed transmission substation basis for system modeling and reliability analysis.

In addition to demands and net energy for load, that portion of demand that is included in or part of controllable demand-side management programs and which may be interrupted by system operators also may be required in evaluating the adequacy and security of the interconnected bulk electric systems.

Standards

S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.

Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall have documentation identifying the scope and details of the actual and forecast (a) demand data, (b) net energy for load data, and (c) controllable demand-side management data to be reported for system modeling and reliability analysis.

The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Standards IB, IIA, and IID.

The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).

M2. The reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region. (S1)

M3. Actual and forecast customer demand data and controllable demand-side management data reported to government agencies shall be consistent with data reported to those entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC. (S1, S2)

M4. The following information shall be provided annually on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D.S1-S2, M1.

1. Integrated hourly demands in megawatts (MW) for the prior year.

2. Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.

3. Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.

4. Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh for at least five years and up to ten years into the future, as requested.

M5. The following information shall be provided on a dispersed substation basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems:

a. Seasonal peak hour actual demands in MW and Mvars for the prior year (as defined in M1 and M2).

b. Seasonal peak hour forecast demands in MW and Mvars (as defined in M1 and M2).

M6. The actual and forecast customer demand data reported on either an aggregated or dispersed basis shall:

a. indicate whether the demand data of nonmember entities within an area or Region are included, and

b. address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and net energy for load.

Full compliance requires items (a) and (b) to be addressed as described in the reporting procedures developed for Measurement M1 of this Standard II.D. Current information on items a) and b) shall be reported to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request (within 30 days). (S1)

M7. Assumptions, methods, and the manner in which uncertainties are addressed in the forecasts of aggregated peak demands and net energy for load shall be provided to the Regions and NERC on request. (S1)

M8. The actual and forecast demand data used in system modeling and reliability analyses (by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC) shall be consistent with the actual and forecast demand data provided under this II.D. Standard on Actual and Forecast Demands. (S1)

M9. Customer demands that are included in or part of controllable demand-side management programs, such as interruptible demands and direct control load management, shall be separately provided on an aggregated Regional, subregional, power pool, and individual system basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M10. Forecasts of interruptible demands and direct control load management data shall be provided annually for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D.S1-S2, M1.

M11. The amount of interruptible demands and direct control load management shall be made known to system operators and security center coordinators on request.

Full compliance requires the reporting of this data to system operators and security center coordinators with 30 days of a request. (S2)

M12. Forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.

Information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load shall be inclueded in the data reporting procedures of Measurement M1 of this Standard II.D.

Documentation on the treatment of demand-side management programs shall be available to NERC on request (within 30 days). (S2)

Guides

G1. System modeling and reliability analyses may be required for more than a five-year period for several reasons including review or comparison of results from previous studies, regulatory requirements, long lead-time facilities (e.g., transmission lines), and government requirements (e.g., construction and/or environmental permits).

G2. Actual and forecast demand data and forecast controllable demand-side management data should be provided on either an aggregated or dispersed basis in an appropriate common format to ensure consistency in reporting and to facilitate use of the data by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC.

G3. Weather normalized data, when provided in addition to actual data, should be identified as such and reconciled as appropriate.

G4. The characteristics of demand-side management programs used in assessing future resource adequacy should generally include:

- consistent program ratings (demand and energy), including seasonal variations
- effect on annual load shape
- availability, effectiveness, and diversity
- contractual arrangements
- expected program duration
- effects (demand and energy) of multiple programs

Introduction

The various components of customer demand respond differently to changes in system voltage and frequency. Seasonal and time-of-day variations may also affect the components and response characteristics of customer demands. Accurate representation of these customer demand characteristics is needed in system modeling since they can have important effects on system reliability.

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall develop a plan for determining and promoting the accuracy of the representation of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting.

Documentation of these customer demand characteristics (dynamic) plans and reporting procedures shall be provided to NERC and the Regions on request. (S1)

M2. The NERC System Dynamics Database Working Group or its successor group(s) shall maintain and publish customer demand characteristics requirements in its "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be maintained and published by the Western (***WECC***), ERCOT, and Hydro-Québec[1] Interconnections. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands. (S1)

M3. Load-serving entities shall provide customer demand characteristics to the Regions and those entities responsible for the reliability of the interconnected transmission systems in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[4] (S1)

[1]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Guides

G1. The representation of customer demands should generally include a combination of constant MVA, constant current, and constant impedance for real and reactive power components and frequency dependence, as appropriate.

G2. Special demand models for significant frequency and voltage dependent customer demands, such as fluorescent lighting or motors, should be provided on request.

G3. Demand characteristics for zones or areas within electric systems or at substation buses should reflect the composition of the demand at those locations.

G4. The voltage and frequency characteristics of customer demands that are used in system models should be representative of seasonal and time-of-day variations, as appropriate.

G5. The representation of customer demand characteristics should be periodically reviewed and field tested, as appropriate, to ensure the accuracy of the demand modeling.

G6. The sensitivity of simulation results to the demand models should be evaluated. High sensitivity demands (e.g., motors and certain substation demands) should generally be represented by more detailed models.

Protection and control systems are essential to the reliable operation of the interconnected transmission networks. They are designed to automatically disconnect components from the transmission network to isolate electrical faults or protect equipment from damage due to voltage, current, or frequency excursions outside of the design capability of the facilities. Control systems are those systems that are designed to automatically adjust or maintain system parameters (voltages, facility loadings, etc.) within pre-defined limits or cause facilities to be disconnected from or connected to the network to maintain the integrity of the overall bulk electric systems.

The objectives for protection and control systems generally include:

- DEPENDABILITY - a measure of certainty to operate when required,
- SECURITY - a measure of certainty not to operate falsely,
- SELECTIVITY - the ability to detect an electrical fault and to affect the least amount of equipment when removing or isolating an electrical fault or protecting equipment from damage, and
- ROBUSTNESS - the ability of a control system to work correctly over the full range of expected steady-state and dynamic system conditions.

A reliable protection and control system requires an appropriate level of protection and control system redundancy. Increased redundancy improves dependability but it can also decrease security through greater complexity and greater exposure to component failure.

Protection and control system reliability is also dependent upon sound testing and maintenance practices. These practices include defining what, when, and how to test equipment calibration and operability, performing preventive maintenance, and expediting the repair of faulty equipment.

Diagnostic tools, such as fault and disturbance recorders, can provide a record of protection and control system performance under various transmission system conditions. These records are often the only means to diagnose protection and control anomalies. Such information is also critical in determining the causes of system disturbances, the sequence of disturbance events, and developing necessary corrective and preventive actions. In some instances, these records provide information about incipient conditions that would lead to future transmission system problems.

Coordination of protection and control systems is vital to the reliability of the transmission networks. The reliability of the transmission network can be jeopardized by unintentional and unexpected automatic control actions or loss of facilities caused by misoperation or uncoordinated protection and control systems. If protection and control systems are not properly coordinated, a system disturbance or contingency event could result in the unexpected loss of multiple facilities. Such unexpected consequences can result in unknowingly operating the electric systems under unreliable conditions including the risk of a blackout, if the event should occur.

The design of protection and control systems must be coordinated with the overall design and operation of the generation and transmission systems. Proper coordination requires an understanding of:

- The characteristics, operation, and behavior of the generation and transmission systems and their protection and control,
- Normal and contingency system conditions, and
- Facility limitations that may be imposed by the protection and control systems.

Coordination requirements are specifically addressed in the areas of communications, data monitoring, reporting, and analysis throughout the **Standards, Measurements, and Guides** under System Protection and Control (III).

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Protection and Control (III) are provided in the following sections:

A. Transmission Protection Systems
B. Transmission Control Devices
C. Generation Control and Protection
D. Underfrequency Load Shedding
E. Undervoltage Load Shedding
F. Special Protection Systems

These **Standards, Measurements, and Guides** shall apply to all protection and control systems necessary to achieve interconnected transmission network performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

The goal of transmission protection systems is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred.

The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure or misoperation of the protection system and the need to maintain overall system reliability.

Standards

S1. Transmission protection systems shall be provided to ensure the system performance requirements as defined in the I.A. Standards on Transmission Systems and associated Table I.

S2. Transmission protection systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I.

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

S4. Transmission protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Transmission or protection system owners shall review their transmission protection systems for compliance with the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I. Any non-compliance shall be documented, including a plan for achieving compliance. Documentation of protection system reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S1)

M2. Where redundancy in the protection systems due to single protection system component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated. (S2)

Each Region shall also develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:

1. Requirements for monitoring and analysis of all transmission protective device misoperations.
2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.
3. Process for review, follow up, and documentation of corrective action plans for misoperations.
4. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.
5. Regional definition of misoperations.

Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30 days). (S3)

M4. Transmission protection system owners shall have a protection system maintenance and testing program in place. This program shall include protection system identification, schedule for protection system testing, and schedule for protection system maintenance.

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S4)

M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.

Guides

G1. Protection systems should be designed to isolate only the faulted electric system element(s), except in those circumstances where additional elements must be removed from service intentionally to preserve electric system integrity.

G2. Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault.

G3. The relative effects on the interconnected transmission systems of a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters.

G4. Protection systems and their associated maintenance procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling.

G5. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition.

G6. Communications channels required for protection system operation should be either continuously monitored, or automatically or manually tested.

G7. Models used for determining protection settings should take into account significant mutual and zero sequence impedances.

G8. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance.

G9. Protection and control systems should be functionally tested, when initially placed in service and when modifications are made, to verify the dependability and security aspects of the design.

G10. Protection system applications should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

G11. The protection system testing program should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing.

G12. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems.

G13. When two independent protection systems are required, dual circuit breaker trip coils should be considered.

G14. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

G15. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered.

G16. Protection system applications and settings should not normally limit transmission use.

G17. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

Introduction

Certain transmission devices are planned and designed to provide dynamic control of electric system quantities, and are usually employed as solutions to specific system performance issues. They typically involve feedback control mechanisms using power electronics to achieve the desired electric system dynamic response. Examples of such equipment and devices include: HVDC links, active or real power flow control and reactive power compensation devices using power electronics (e.g., unified power flow controllers (UPFCs), static var compensators (SVCs), thyristor-controlled series capacitors (TCSCs), and in some cases mechanically-switched shunt capacitors and reactors.

In planning and designing transmission control devices, it is important to consider their operation within the context of the overall interconnected systems over a variety of operating conditions. These control devices can be used to avoid degradation of system performance and cascading outages of facilities. If not properly designed, the feedback controls of these devices can become unstable during weakened system conditions caused by disturbances, and can lead to modal interactions with other controls in the interconnected systems.

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurements

M1. When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems. The assessment shall include sufficient modeling of the details of the dynamic devices and encompass a variety of contingency system conditions. The assessment results shall be provided to the Regions and NERC on request. (S1)

M2. Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization. (S1)

M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the Regions and NERC on request. (S1)

Guides

G1. Coordinated control strategies for the operation of transmission control devices may require switching surge studies, harmonic analyses, or other special studies.

G2. For HDVC links in parallel with ac lines, supplementary control should be considered so that the HDVC links provide synchronizing and damping power for interconnected generators. Use of HDVC links to stabilize system ac voltages should be considered.

Introduction

Generator excitation and prime mover controls are key elements in ensuring electric system stability and reliability. These controls must be coordinated with generation protection to minimize generator tripping during disturbance-caused abnormal voltage, current, and frequency conditions. Generators are the primary method of electric system dynamic voltage control, and therefore good performance of excitation equipment (exciter, voltage regulator, and, if applicable, power system stabilizer) is essential for electric system stability. Prime mover controls (governors) are the primary method of system frequency regulation.

Generator control and protection must be planned and designed to provide a balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generating equipment from damage. Unnecessary generator tripping during a disturbance aggravates the loading conditions on the remaining on-line generators and can lead to a cascading failure of the interconnected electric systems.

Accurate data that describes generator characteristics and capabilities is essential for the studies needed to ensure the reliability of the interconnected electric systems. Protection characteristics and settings affecting electric system reliability must be provided as requested.

Standards

S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.

S2. Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.

S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

S5. Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

S6. All generation protection system trip misoperations shall be analyzed for cause and corrective action.

S7. Generation protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Generation equipment owners shall provide, upon request, the Region and transmission system operator a log that specifies the date, duration, and reason for each period when the generator was not operated in the automatic voltage control mode. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S1)

M2. When requested by the transmission system operator, the generating equipment owner shall provide a log that specifies the date, duration, and reason for a generator not maintaining the established network voltage schedule or reactive power output. (S2)

M3. The generation equipment owner shall provide the transmission system operator with the tap settings and available ranges for generator step-up and auxiliary transformers. When tap changes are necessary to coordinate with electric system voltage requirements, the transmission system operator shall provide the generation equipment owner with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S2)

M4. When requested, generating equipment owners shall provide the Region and transmission system operator with the operating characteristics of any generator's equipment protective relays or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator. The more common protective relays include volts per hertz, loss of excitation, underfrequency, overspeed, and backup distance. (S3)

M5. Upon request, generating equipment owners shall provide the Region and transmission system operator with information that describes how generator controls coordinate with the generator's short term capabilities and protective relays. (S4)

M6. Overexcitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic ac voltage regulator to reduce field current to the continuous rating. Return to normal ac voltage regulation after current reduction shall be automatic. The overexcitation limiter shall be coordinated with overexcitation protection so that overexcitation protection only operates for failure of the voltage regulator/limiter. (S4)

M7. Upon request, generating equipment owners shall provide the Region or transmission system operator with information that describes the characteristics of the speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance to the extent possible while meeting the safety requirements of the plant. Nonfunctioning or blocked speed/load governor controls shall be reported to the Region and transmission system operator. (S5)

M8. Each Region shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Documentation of protection trip misoperations shall be provided to the affected Regions and NERC on request. (S6)

M9. Generation equipment owners shall have a generation protection system maintenance and testing program in place. Documentation of the implementation of protection system maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S7)

Guides

G1. Power system stabilizers improve damping of generator rotor speed oscillations. They should be applied to a unit where studies have determined the possibility of unit or system instability and where the condition can be improved or corrected by the application of a power system stabilizer. Power system stabilizers should be designed and tuned to have a positive damping effect on local generator oscillations and on inter-area oscillations without deteriorating turbine/generator shaft torsional oscillation damping.

G2. Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance.

G3. Generator control and protection should be periodically tested to the extent practical to ensure the generator plant can provide the designed control, and operate without tripping for specified voltage, frequency, and load excursions. Control responses should be checked periodically to validate the model data used in simulation studies.

G4. New or upgraded excitation equipment should consider high initial response, as inherent in brushless or static exciters.

G5. Generator step-up transformer and auxiliary transformers should have tap settings that are coordinated with electric system voltage control requirements and which do not limit maximum use of the reactive capability (lead and lag) of the generators.

G6. Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed +/- 0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

G7. Prime mover overspeed controls to the extent practical should be designed and adjusted to prevent boiler upsets and trips during partial load rejection characterized by abnormally high system frequency.

G8. Generator voltage regulators to the extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

G9. New or upgraded excitation equipment to the extent practical should have an exciter ceiling voltage that is generally not less than 1.5 times the rated output field voltage.

G10. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B, and C of the I.A. Standards on Transmission Systems, unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Introduction

A coordinated automatic underfrequency load shedding (UFLS) program is required to help preserve the security of the generation and interconnected transmission systems during major declining system frequency events. Such a program is essential to minimize the risk of total system collapse, protect generating equipment and transmission facilities against damage, provide for equitable load shedding (interruption of electric supply to customers), and help ensure the overall reliability of the interconnected systems.

Load shedding resulting from a system underfrequency event should be controlled so as to balance generation and customer demand (load), permit rapid restoration of electric service to customer demand that has been interrupted, and when necessary re-establish transmission interconnection ties.

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurements

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:

a. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.
b. Design details including size of coordinated load shedding blocks (% of connected load), corresponding frequency set points, intentional delays, related generation protection, tie tripping schemes, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UFLS programs.
c. A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.
d. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:

1. A review of the frequency set points and timing, and
2. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.

e. Determination, as appropriate, of maintenance, testing, and calibration requirements by member systems.

Documentation of each Region's UFLS program and its database information shall be current and provided to NERC on request (within 30 days).

Documentation of the current technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days). (S1)

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measurement M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update and UFLS program as specified in Measurement M1.

The documentation of an entity's UFLS program shall be provided to the Region on request (within 30 days). (S1)

M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

These programs shall be maintained and documented, and the results of implementation shall be provided to the Regions and NERC on request (within 30 days).

M4. Those entities owning or operating UFLS programs shall analyze and document their UFLS program performance in accordance with Standard III.D. S1-S2, M1, including the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

1. A description of the event including initiating conditions
2. A review of the UFLS set points and tripping times
3. A simulation of the event
4. A summary of the findings

Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.

Guides

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies. These studies are critical to coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

G2. The UFLS programs should be coordinated with generation protection and control, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control.

G3. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G4. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G5. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G6. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G7. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G8. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G9. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G10. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G11. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration.

Introduction

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

It is imperative that undervoltage relays be coordinated with other system protection and control devices used to interrupt electric supply to customers.

Standards

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measurements

M1. Those entities owning or operating UVLS programs shall coordinate and document their UVLS programs including descriptions of the following:

a. Coordination of UVLS programs within the subregions, the Region, and, where appropriate, among Regions.

b. Coordination of UVLS programs with generation protection and control, UFLS programs, Regional load restoration programs, and transmission protection and control programs.

c. Design details including size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.

Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request. (S1, S2)

M2. Those entities owning or operating UVLS programs shall ensure that their programs are consistent with any Regional UVLS programs and that exist including automatically shedding load in the amounts and at locations, voltages, rates, and times consistent with any Regional requirements. (S1)

M3. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UVLS program. Documentation of the UVLS technical assessment shall be provided to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating UVLS programs shall have a maintenance program to test and calibrate their UVLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

M6. Those entities owning or operating an UVLS program shall analyze and document all system undervoltage events below the initiating set points of their UVLS programs. Documentation of the analysis shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. UVLS programs should be coordinated with other system protection and control programs (e.g., timing of line reclosing, tap changing, overexcitation limiting, capacitor bank switching, and other automatic switching schemes).

G2. Automatic UVLS programs should be coordinated with manual load shedding programs.

G3. Manual load shedding programs should not include, to the extent possible, customer demand that is part of an automatic UVLS program.

G4. Assessments of UVLS programs should include system dynamic simulations that represent generator overexcitation limiters, load restoration dynamics (tap changing, motor dynamics), and shunt compensation switching.

G5. Plans to shed load automatically should be examined to determine if acceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

Introduction

A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings.

The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the **NERC Planning Standards** must ensure that the SPS is highly reliable.

Examples of SPS misoperation include, but are not limited to, the following:

1. The SPS does not operate as intended.
2. The SPS fails to operate when required.
3. The SPS operates when not required.

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A. Standards on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

S4. All SPS misoperations shall be analyzed for cause and corrective action.

S5. SPS maintenance and testing programs shall be developed and implemented.

Measurements

M1. Each Region whose members use or are planning to use an SPS shall have a documented Regional review procedure to ensure the SPS complies with Regional criteria and guides and **NERC Planning Standards**. The Regional review procedure shall include:

1. Description of the process for submitting a proposed SPS for Regional review.
2. Requirements to provide data that describes design, operation, and modeling of an SPS.
3. Requirements to demonstrate that the SPS design will meet above SPS Standards S1 and S2.
4. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional emergency procedures.
5. Regional definition of misoperation.
6. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.
7. Identification of the Regional group responsible for the Region's review procedure and the process for Regional approval of the procedure.
8. Determination, as appropriate, of maintenance and testing requirements.

Documentation of the Regional SPS review procedure shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3, S4)

M2. A Region that has a member with an SPS installed shall maintain an SPS database. The database shall include the following types of information:

1. Design Objectives – Contingencies and system conditions for which the SPS was designed,
2. Operation – The actions taken by the SPS in response to disturbance conditions, and
3. Modeling – Information on detection logic or relay settings that control operation of the SPS.

Documentation of the Regional database or the information therein shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M3. A Region shall assess the operation, coordination, and effectiveness of all SPSs installed in the Region at least once every five years for compliance with NERC Planning Standards and Regional criteria. The Regions shall provide either a summary report or a detailed report of this assessment to affected Regions or NERC, on request (within 30 days). The documentation of the Regional SPS assessment shall include the following elements:

1. Identification of group conducting the assessment and the date the assessment was performed.
2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.

3. Identification of SPSs that were found not to comply with NERC Planning Standards and Regional criteria.
4. Discussion of any coordination problems found between an SPS and other protection and control systems.
5. Provide corrective action plans for non-compliant SPSs. (S1, S2, S3)

M4. SPS owners shall maintain a list of and provide data for existing and proposed SPSs as defined in Measurement III.F. S1-S3, M2. New or functionally modified SPSs shall be reviewed in accordance with the Regional procedures as defined in Measurement III.F. S1-S4, M1 prior to being placed in service.

Documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Planning Standards and Regional criteria shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations.

Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days). (S4)

M6. SPS owners shall have an SPS maintenance and testing program in place. This program shall include the SPS identification, summary of test procedures, frequency of testing, and frequency of maintenance. Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S5)

Guides

G1. Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational.

G2. No identifiable common mode events should result in the coincident failure of two or more SPS components.

G3. An SPS should be designed to operate only for conditions that require specific protective or control actions.

G4. As system conditions change, an SPS should be disarmed to the extent that its use is unnecessary.

G5. SPSs should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

G6. The design of SPSs both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance. Test facilities and test procedures should be designed such that they do not compromise the independence of redundant SPS groups.

G7. SPSs that rely on circuit breakers to accomplish corrective actions should as a minimum use separate trip coils and separately fused dc control voltages.

A blackout is a condition where a major portion or all of an electrical network is de-energized resulting in loss of electric supply to a portion or all of that network's customer demand. Blackouts will generally take place under two typical scenarios:

- Dynamic instability, and
- Steady-state overloads and/or voltage collapse.

Blackouts are possible at all loading levels and all times in the year. Changing generation patterns, scheduled transmission outages, off-peak loadings resulting from operations of pumped storage units, storms, and rapid weather changes among other reasons can all lead to blackouts. Systems must always be alert to changing parameters that have the potential for blackouts.

Actions required for system restoration include identifying resources that will likely be needed during restoration, determining their relationship with each other, and training personnel in their proper application. Actual testing of the use of these strategies is seldom practical. Simulation testing of restoration plan elements or the overall plan are essential preparations toward readiness for implementation on short notice.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Restoration (IV) are provided in the following sections:

A. System Blackstart Capability
B. Automatic Restoration of Load

These **Standards, Measurements, and Guides** address only two aspects of an overall coordinated system restoration plan. From a planning standpoint, it is critical that any overall system restoration plans include adequate generating units with system blackstart capability. It is also important that adequate facilities are planned for the interconnected transmission systems to accommodate the special requirements of system restoration plans such as switching and sectionalizing strategies, station batteries for dc loads, coordination with under-frequency and undervoltage load shedding programs and Regional or area load restoration plans, and facilities for adequate communications.

Automatic restoration of load following a blackout helps to minimize the duration of interruption of electric service to customer demands. However, these automatic systems must be coordinated with other Regional load restoration activities and included in the components of overall system restoration plans.

Introduction

Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators. They must be able to self-start without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators. Generators that can safely reject load down to their auxiliary load are another form of blackstart generator that can aid system restoration.

From a planning perspective, a system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional system restoration plans.

Standards

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.

Measurements

M1. Each Region shall establish and maintain a system blackstart capability plan that shall be coordinated, as appropriate, with the blackstart capability plans of neighboring Regions. Documentation of system blackstart capability plans shall be provided to NERC on request. (S1)

M2. Regions shall maintain a record of all system blackstart generators within their respective areas and update such records on an annual basis. The record shall include the name, location, MW capacity, type of unit, date of test, and starting method of each system blackstart generating unit. (S1)

M3. The owner or operator of each system blackstart generating unit shall demonstrate at least every five years, through simulation or testing, that the unit can perform its intended functions as required in the system restoration plan. Documentation of the analysis shall be provided to the Region and NERC on request. (S1)

M4. The results of periodic tests of the startup and operation of each system blackstart generating unit shall be documented and provided to the Region and NERC on request. (S2)

M5. Each Region shall verify that the number, size, and location of system blackstart generating units are sufficient to meet system restoration plan expectations. (S1)

Guides

G1. Analyses should ensure that a system blackstart generating unit is capable of maintaining adequate regulation of voltage and frequency.

G2. Analyses should include evaluation of blackstart generator protection and control systems during the abnormal conditions that will exist during system restoration.

G3. Actual physical testing of system blackstart generating unit procedures should be performed where practical or feasible.

G4. When limited energy resources (e.g., hydro, pumped storage hydro, compressed air) are used for blackstart, the system blackstart capability plan timing considerations should include a range of limiting energy conditions.

Introduction

If properly coordinated and implemented, automatic restoration of load can be useful to minimize the duration of interruption of electric service to customer demands. However, care must be taken to ensure that automatic restoration of load does not impede restoration of the interconnected bulk electric systems.

After automatic load shedding (by either underfrequency or undervoltage relays) has occurred, use of automatic restoration of load after the electric systems have recovered sufficiently (systems stabilized, frequency near nominal, and voltages within appropriate limits) can speed the reenergization of customer demands and minimize delays in restoring the electric systems.

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurements

M1. Those entities owning or operating an automatic load restoration program shall coordinate, document, review, and implement their programs in compliance with Regional programs for load restoration. Documentation of automatic load restoration programs shall be provided to the appropriate Regions and NERC on request. (S1)

M2. Documentation of automatic load restoration programs shall include:

a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Region and, where appropriate, among Regions.

b. Automatic load restoration design details including size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays). (S1)

M3. Each Region shall maintain and annually update an automatic load restoration program database. This database shall include sufficient information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating an automatic load restoration program shall conduct and document a technical assessment of the effectiveness of the design and implementation of their programs including their relationship to under-frequency and undervoltage load shedding programs in the Region. Documentation of the technical assessments of automatic load restoration programs shall be available to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating automatic load restoration programs shall have a maintenance program to test and calibrate the automatic load restoration relays to ensure accurate and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. Relays installed to restore load automatically should be set with varying and relatively long time delays, except for that portion of the automatic load restoration, if any, that is designed to protect against frequency overshoot.

G2. The design of automatic load restoration programs should consider the system effects of reenergizing large blocks of customer demand.

G3. Major interconnection tie lines should generally be restored to service before automatic restoration of load is implemented.

References

The references in this section are provided as background information for the users of the **NERC Planning Standards**. This list is comprised of recommendations from the various members of the NERC Engineering Committee's subgroups that participated in the development of the **NERC Planning Standards**.

Except for NERC references, the references in the following list have not been reviewed or endorsed by NERC or any of its subgroups. However, these references should aid the reader who wants an understanding of specific technical areas addressed in the **NERC Planning Standards**.

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